Closed-Loop Energy Management Control of Large Industrial Facilities

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Abstract

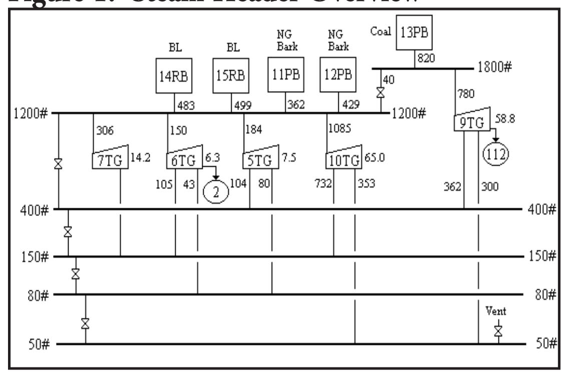
A case study is presented of a closed-loop control system installed and running at a pulp and paper facility in the southeast. A fuzzy logic, ruled-based control system optimally loads multiple steam turbines for maximum electrical generation, while providing steam to the process. A Sell Advisor calculates make–buy decisions based on real-time electrical prices, fuel prices and boiler loads. Condensing turbines are coordinated with closed-loop control to provide the lowest energy cost to the plant. When economical, additional electrical generation is achieved by venting low-pressure steam. By manipulating turbine loads, boilers are pushed to optimal loading through process coupling. Multi-variable control strategies push process envelopes to constraints.

Background

Deregulation of electricity and rising fuel costs are causing renewed interest in energy management systems (EMS). This paper details the results of integrating a rule-based EMS controller at a pulp and paper mill and additional findings from several other large industrial power complexes. It is a computer-based supervisory system that is interfaced to a distributed control system (DCS). The EMS has been applied on powerhouse complexes as large as 433 MW of electricity and 7,500 KPPH of steam. The EMS may, as required, include boiler load allocation, steam turbine load allocation, combustion turbine and heat recovery steam generator load allocation, real-time pricing (RTP) tie-line control, coordinated header pressure control, bus voltage and plant power factor control and electric and steam economic load shed systems. It optimizes the powerhouse operations to meet rapidly changing steam and electrical requirements of the plant at minimum cost subject to all of the operating constraints imposed on the generation equipment.

It is critical to control the trajectory of the power generation for optimal steam and electric moves while satisfying multiple constraints. The optimization strategy applied here is reduced to a fairly small number of prioritized rules. It has proven itself capable of optimizing large powerhouse complexes while keeping the powerhouse and process units within a safe operating envelope.

Figure 1: Steam Header Overview



The purchased energy (fossil fuel and electricity) cost component for producing a product can be significant, and small incremental changes can make a big impact on the profitability of a plant. The plant studied here is minimizing purchased fuel and maximizing waste fuel usage to reduce energy cost and emissions.

The powerhouse has a number of environmental, equipment and process constraints that must be adhered to as the powerhouse equipment is maneuvered to meet the mill's energy demand at the lowest possible cost. Balancing the optimization functions with all of those constraints is a difficult task requiring a significant amount of operator intervention. A closed-loop, multi-variable, EMS is used to control multiple operating objectives.

Control Objectives

Several objectives were identified and prioritized as follows:

1. Maximize steam supplied by self-generated waste fuel sources such as hog and black liquor.
2. Optimize power boiler loading to produce the mill's steam requirement at the lowest cost.
3. Balance turbine loads to produce maximum electrical generation while supplying process steam.
4. Manage turbine condensing to buy, make or sell power based on electrical schedules and real-time electrical prices, fuel costs and boiler efficiencies.
5. Vent 50-psig steam to generate additional electricity when economical based on real time prices, fuel costs and boiler efficiencies.

Buy/Sell Advisor

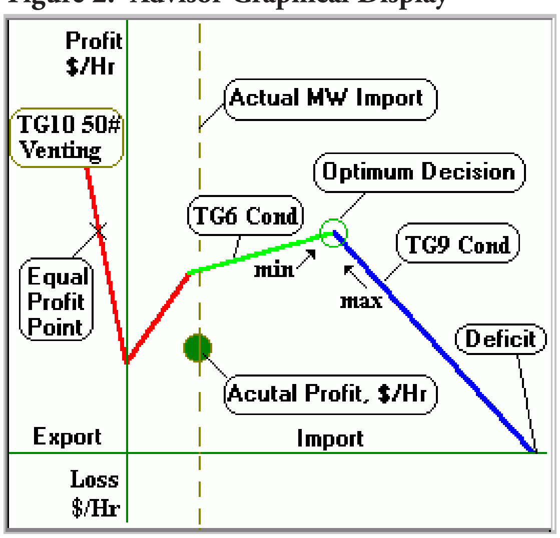
An operator sell advisor was developed for the following reasons:

1. Show operators how to optimally load turbines.
2. Calculate global buy/make/sell purchase decisions based on incremental cost calculations and risk assessment.
3. Provide performance indicators to track EMS performance.

Optimal turbine loading is displayed to the operators both graphically and numerically. Each line is color coded to represent a specific turbine extraction, exhaust or condensing flow. Incremental fuel costs, boiler efficiencies and turbine stage efficiencies contribute to changes in the overall cost of energy.

Shown in Figure 2, the vertical axis represents potential $/hr. profit or loss. The horizontal axis represents electrical power export or import in Megawatts. Shown at the far right is the electrical deficit. Electrical deficit is defined as the difference between total plant electrical load minus megawatts produced internally with minimum turbine condensing and no venting to the atmosphere. Profit or loss is compared against buying all of the electrical deficit. Every 15 minutes, real-time electrical prices are downloaded automatically by EMS. Based on incremental cost calculations, EMS continuously decides to make or buy the electrical deficit while observing multiple constraints.

Figure 2: Advisor Graphical Display



The graph in Figure 2 indicates the optimum decision is to maximize TG9 condensing load and minimize TG6 condensing load. Increasing TG6 condensing load reduces $/hr. profit. The dashed, vertical line shows current tie-line power import. In this case, TG9 condensing should be maximized and TG6 condensing should be minimized to maximize overall profit. On EMS control, TG9 and TG6 condensing loads are maneuvered automatically to maximize profit.

Sometimes, selling power to the grid may be profitable based on current electrical prices. As shown in Figure 2, a conflicting decision is often seen where it is better to buy the electrical deficit than to make it, but possible to sell power at a profit.

In Figure 2, an equal profit point represents the minimum amount of power that must be sold to match profits obtained by optimally purchasing power. Under these conditions, EMS decides to buy or sell based on risk assessment calculations. Risk calculations are based on potential return on investment versus the potential loss trying to obtain the return. Risk factors include current equipment loading, process stability and real-time electrical prices. Risk factors are adjustable to match Operations' comfort level. Advice is summarized, as shown Figure 3.

Performance Indicators

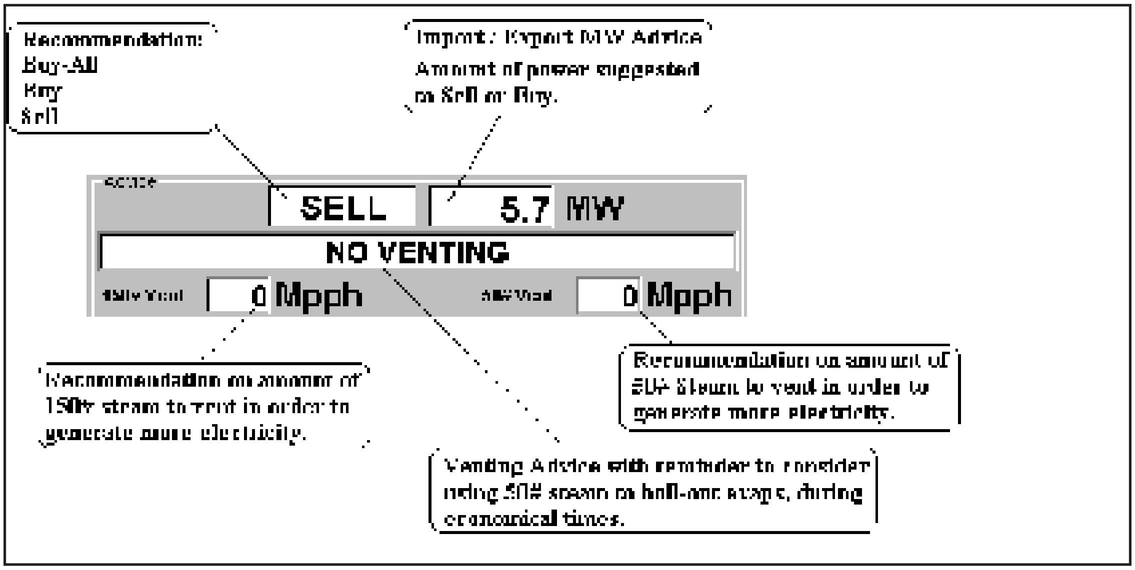
In Figure 4, a performance display is provided to show either Operator or EMS performance based on current operating conditions and incremental profit calculations. The display indicates maximum and actual $/hr. profit values and shows potential savings possible. A performance bar shows overall economic header balance in degrees of good or bad.

EMS Benefits

EMS has been in continuous automatic operation at this site since April 2001. Many significant benefits have been achieved:

1. Substantial reduction in overall cost of energy
   - Reduced natural gas usage
   - Reduced overall steam production
   - Reduced overall cost of electrical deficit
   - Reduced overall turbine condensing
   - Reduced selling of electrical power
   - Increased turbine power from process steam
   - Less venting during transient upsets

Figure 3: Advice



2. Greater power boiler operating stability
   - Reduced natural gas usage
   - Higher percentage of steam from hog fuel
   - Considerable cost savings
3. Reduced power boiler steam production
   - Reduced steam production overall
   - Considerable cost savings
   - Reduced stack emissions
4. Stable operation identified bottlenecks
   - Units run consistently on the edge of optimal performance
5. System indicators identify constraints
6. Steam users report more stable header pressures
7. Accelerated Return on Investment (ROI)
   - Original ROI estimate was one year
   - Actual ROI was less than six months
   - Contractual performance testing was waived to maintain increase in profits!

The advantage of a rule-based system is to take the best engineering and operational knowledge and insert it into the control system to be operational 24 hours a day, seven days a week. EMS performs optimization functions while adhering to all constraints. Like the operator, EMS sacrifices cost optimization whenever a constraint is reached. This results in robust process control. The control priorities are:

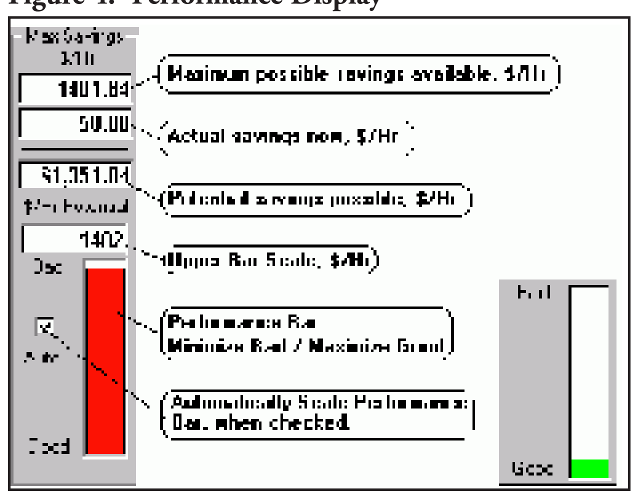
1. Meet all environmental constraints
2. Avoid equipment damage
3. Meet all process constraints
4. Assure utility delivery to process units
5. Meet energy requirements at minimum costs

Steam and Electrical Network

The powerhouse steam header overview is shown in Figure 1. More than half of the steam that is generated comes from burning process byproducts (black liquor and hog). Most of the process steam demand is for low-pressure steam. Steam is generated at higher pressures and throttled through the turbine-generators to lower pressure headers. A significant amount of electrical power, termed "extraction power" or "cogeneration", is generated as a result of this throttling action. PRVs offer an alternative way to throttle the steam to the lower pressure headers. However, since no power is generated, steam flows through PRVs should be minimized.

There is significant variability in the process steam and electrical power demand. Batch di-

Figure 4: Performance Display



gester operation, wood yard log chippers, soot blowers, paper machine disturbances and pulping process upsets all contribute to this variability. A "sheet break" on a large paper machine and subsequent threading of the sheet can result in large sudden steam demand swings in a period of less than a minute. Sometimes the power boilers must go from maximum load to minimum load and back again to maximum load within several minutes. Power boilers seldom operate at steady state conditions unless they are base loaded, i.e., the boiler master is placed in "manual". It is this variability that makes real-time optimization of the powerhouse operations so challenging. Steady state optimization methods simply do not provide the solution when the process is rarely at steady state.

Energy Management System

A new type of EMS has been developed and implemented to minimize the total cost of energy required by an industrial facility. It coordinates and optimizes the generation and distribution of steam as well as the generation and purchase of electricity. It also controls the main steam header pressure. The EMS is a supervisory control system that works in tandem with regulatory controls residing in the powerhouse DCS and PLCs.

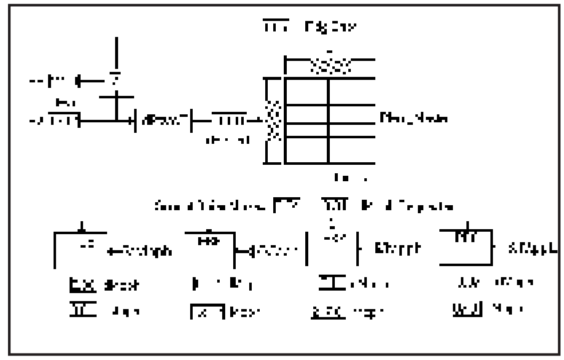
The EMS subsystems include boiler load allocation, turbine load allocation, hog optimization and demand or real-time pricing tie-line control. Each subsystem can be operated independently. The operator selects the subsystem and places it on EMS control. For boiler load allocation, the operator selects which boilers and fuels are to be used. The EMS control software resides in a Windows NT personal computer or can be installed directly in the DCS. It has been designed specifically for implementing fuzzy logic control. There are interfaces to the powerhouse DCS, turbine controllers and various PLCs.

Boiler Load Allocation

A schematic of a typical 1,200-psig header pressure control with an embedded boiler cost optimizer is shown in Figure 5.

The plant master is implemented with a fuzzy matrix controller that offers some significant advantages over a PID version. Fuzzy matrix controllers can exhibit superior control performance compared to a PID controller, especially for a nonlinear, complex process. The tuning of fuzzy controllers is a trial and error procedure that involves

Figure 5: Typical Boiler Cost Optimization

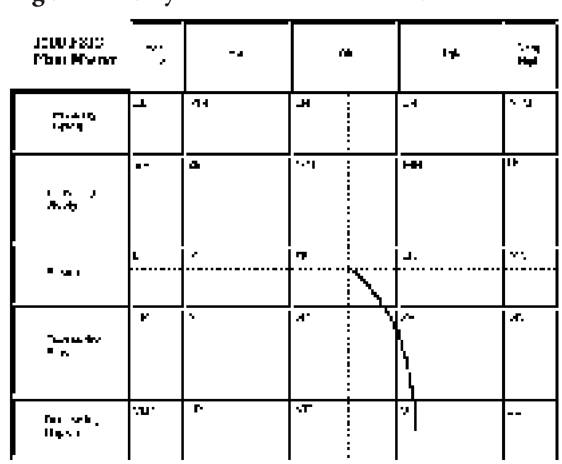


adjusting many parameters. A simple method to help with the tuning of fuzzy controllers has been developed. By overlaying a phase-plane plot on the rule matrix and analyzing the phase-plane trajectories, it becomes relatively easy to adjust membership functions and modify the rules to obtain the desired trajectories.

The fuzzy controller executes once per second and sends a request to the boiler cost optimizer for an incremental steam change. The boiler load optimizer design involves integration of three distinct functions. A safe operating envelope representing prioritized environmental, equipment and process constraints are defined which the allocator must respect. An optimization method is used which adjusts multiple boilers and fuels to obtain the most economical operating solution. The issue of header pressure control stability is addressed so power boilers with widely varying response capabilities can work in concert. Balancing these three functions is key to a successful design.

The boiler load allocator observes all predefined constraints before adjusting boiler fuel flows. These constraints create a safe operating envelope. Observing constraints prevents boiler damage and keeps the process out of undesirable operating re-

Figure 6: Fuzzy Matrix Plant Master Controller



gions. Constraints are prioritized in order of importance. Typical constraints for a boiler are (listed in order of priority):

1. Maintain opacity (6-minute average) below maximum.
2. Keep ID fan speed within control range.
3. Prevent furnace draft from going positive.
4. Maintain drum level in safe range.
5. Prevent excess oxygen from going too low.
6. Keep boiler steam generation within limits.

The boiler load allocation problem is analogous to the economic dispatching problem faced by an electric utility company whenever transmission losses can be ignored. For optimal allocation, the utilities must operate the units at equal incremental generating costs. Often the boiler load allocation problem has been posed as a static optimization problem. But in reality, the allocation function is embedded in the header pressure control loop that transforms it into a dynamic control problem. Since there are continuous disturbances to header pressure (caused by variations in steam demand), boiler load allocation also takes place on a continuous basis. Direct application of steady state optimization methods does not work for a process that is never at steady state. Instead, a dynamic boiler allocation method is used. In this solution, the optimization method has been converted to an optimization rule set that is integrated into the overall rule set.

An incremental steam generation cost (dollars per thousand pounds of steam) is continuously calculated for each boiler (fuel) based on the fuel cost (dollars per MMBtu), the selected swing fuel and incremental boiler efficiency for the selected fuel. This efficiency number is entered based on historical data or online calculations.

For incremental steam increase requests, boilers and fuels with lower incremental steam costs are favored more than boilers and fuels that have higher costs. All of the boilers move in concert to prevent one boiler from taking all of the load swings. For incremental steam decrease requests, boilers and fuels with higher incremental steam costs are favored. In the long run, the most economical boilers and fuels take most of the steam load. The more expensive steam producers are kept at a minimum value. In the short term, if more expensive steam is required for good header pressure control, it is used. When properly tuned, the penalty for better header pressure control is usually not significant.

Hog Optimization

Hog optimization is incorporated in the boiler load allocation function. The operator enters a minimum and maximum hog rate limit. It is desired to keep the hog rate for each boiler at its maximum value as much as possible.

In a multi-fuel boiler, each fuel is treated as if it was a separate boiler by the boiler load allocator. The cost of hog ($/MMBtu) is entered as a very low value.

There is a significant lag time (several minutes) associated with the transport of hog from the hog bin to the boilers. This lag time prevents hog from being an effective swing fuel. However, an operator adjustable aggressiveness factor is used to allow hog to be treated as a pseudo swing fuel and maintain stable header pressure control.

Normally, hog flow will remain at the maximum limit (entered by the operator) and header pressure control is accomplished by adjusting gas flows. However, there are periods of low steam demand when hog flow must be reduced to prevent excess venting of steam to the atmosphere. When the fossil fuel is at minimum limits and further steam generation reduction is needed, the boiler allocator will reduce the hog flows of the power boiler. When the process demand increases, hog starts to increase. Hog is considered somewhat base loaded, since it always works its way back to the maximum limit.

Steam System Management

The next area of concentration is steam usage management. The primary focus is the proper allocation of the generated steam to satisfy steam header and system electric generation requirements. The steam system management components are described below.

Header Pressure Control Stability

One of the major challenges of implementing boiler load allocation is to maintain stable header pressure control for all combinations of boilers, fuels and equipment conditions. Boilers have different response times. Variable fuel quality and moisture content can effect the boiler's response time. Mechanical problems can limit the rate of load changes for a boiler.

Multi-fuel boilers, where hog is burned on a traveling grate, seem to create problems. Wet hog, long lag times in the hog feed system and hog piling on the grates can make using the boiler for header pressure control quite challenging.

An aggressiveness factor is assigned to each boiler fuel. It determines how much a boiler fuel is asked to participate in header pressure control. The factor varies from zero to one. When set to zero, the fuel does not participate in header pressure control. It becomes base loaded. When set to one, the boiler fuel has full participation in header pressure control. For any value in between, there is partial participation. Matching the aggressiveness factor to the responsiveness of each boiler is important for achieving stable header pressure control. Reducing the participation of boiler fuels that have poor steaming response is essential. However, there must be at least one boiler fuel (in large plants, preferably two) that has a fast steam response if satisfactory header pressure control is to be obtained.

Sometimes boiler constraints reduce header pressure control effectiveness. Each boiler's constraints are checked once per second to insure process limits are not being violated. As a boiler approaches a limit, its participation in header pressure control is reduced to zero. When some limits are exceeded, such as boiler steam generation, constraint controllers may make counter control moves to place the boiler back inside the safe operating envelope. Counter control moves are usually to the detriment of good header pressure control. This means that the header pressure is not the highest control priority. In fact, it is the lowest priority.

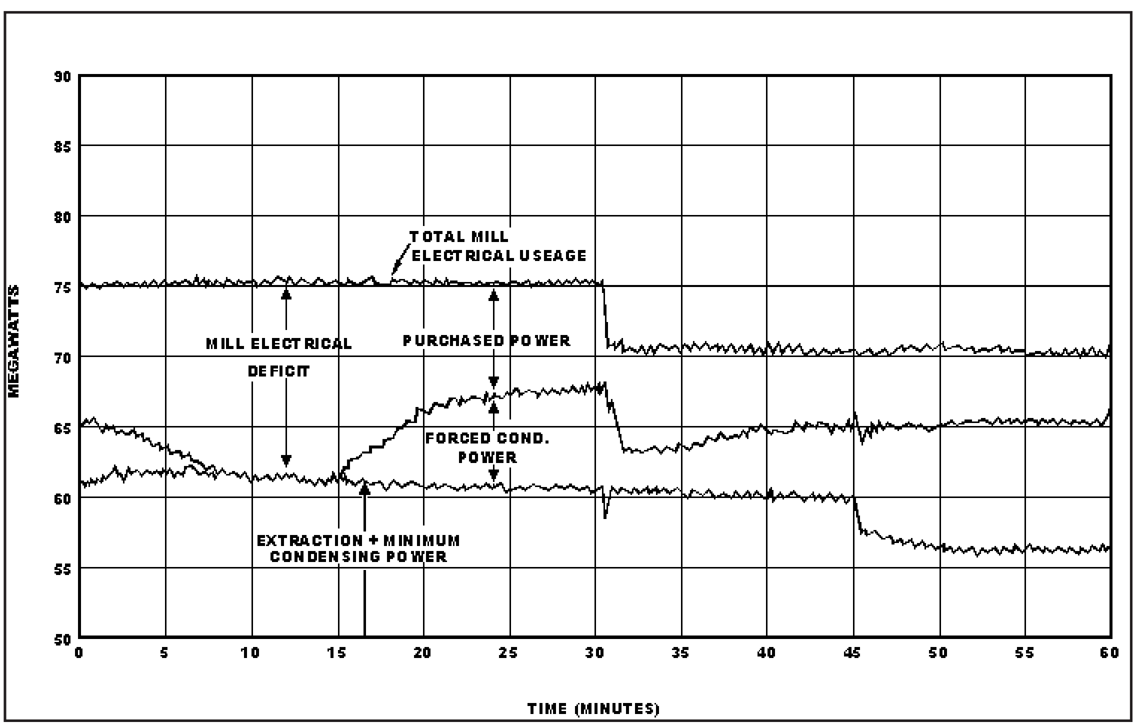
Turbine Lead Allocation

This subsystem provides supervisory control for 400, 150 and 50 psig extraction flows of all turbines to minimize PRV flows and maximize the total power that is generated. Turbines are assigned primary responsibilities to control various header pressures. Turbine extraction and exhaust flows are balanced by adjusting pressure setpoints. RTP tie-line power is adjusted by adjusting the load to the turbine condensers. When economical, additional power is generated by venting 50-psig steam by adjusting pressure setpoints.

A safe operating envelope for turbine load allocation has been defined that will:

1. Maintain all TG parameters (V1, V2, V3, MWs ... etc.) within the minimum and maximum limits.
2. Provide override control for 1,500 and 1,200 psig header pressures (outside of minimum and maximum limits).
3. Provide override control for 400-psig header pressure (outside of minimum and maximum limits).

Figure 7: Electrical Deficit



4. Provide override control for 150-psig header pressure (outside of minimum and maximum limits).
5. Provide override control for 80-psig header pressure (outside of minimum and maximum limits).
6. Provide override control for 50-psig header pressure (outside of minimum and maximum limits).
7. Maintain extraction flows on TG in control range for extraction pressure control.
8. Maintain sufficient swing range for TG's condensing flow to accommodate RTP tie-line control.

EMS adjusts turbine pressure setpoints and condensing load controls to achieve optimum turbine load balancing. Setpoints are "bumped" up or down until constraints are reached.

Electric Utility Rate Schedules

Most industrial customers purchase power from an electric utility company on a 15 or 30 minute interval. This type of rate schedule has a demand component and fixed energy charges for on and off-peak periods. The demand charge is usually based on the highest (peak) interval demand in the last 11 or 12 months. Interval demand is the average purchased power over an interval. Exceeding a previously set peak demand may cost hundreds of thousands of dollars since this new peak demand is usually ratcheted as the minimum demand charge for the following 12 months.

Real Time Pricing (RTP) is a new type of rate schedule offered to industrial customers by many electric utilities. The utility provides tomorrow's hourly prices based on the grid load and generating capability. Under the RTP rate schedule there is no demand charge or demand interval. Instead, the price of electricity varies on an hourly basis. Customers can purchase all of the power they need without worrying about setting a new peak demand. During summer periods, when the power demand becomes high, the midday hourly price is usually quite expensive. On some days it may even exceed $1,000/megawatt hour. The customer obviously doesn't want to buy any more of this expensive electricity than is absolutely necessary.

RTP Tie-Line Control

The ability to select the most attractive electric rate schedule is critical for today's energy manager. In this application the Tie line control has three modes:
1. RTP
2. Demand MW
3. Constant Purchase MW.

However, it is the RTP mode that is becoming more important in the deregulated business environment. In some instances the utility faces utility generation or transmission constraints and will provide attractive economic incentives for excess power generation or demand side management during peak periods. The objective is to reduce the mill electric demand or at some mills, generate power onto the grid during periods of high utility demand. This becomes a "Win-Win" for both the plant and the utility. The primary control objective for the mill is to adjust TG's steam flow to the condenser or vent to minimize the cost of providing the mill electrical deficit while staying within a predefined safe operating envelope.

Mill Electrical Deficit

To implement an RTP or Demand tie line controller, it is necessary to focus on the Mill Electrical Deficit shown in Figure 7. The electrical deficit is defined as the mill's total electrical power demand minus the power being generated due to the turbine's extraction flows and minimum flow to the condenser.

There are three sources of power that can be used to meet the deficit:

1. Purchased power
2. Forced condensing power
3. Venting (50-psig steam) power

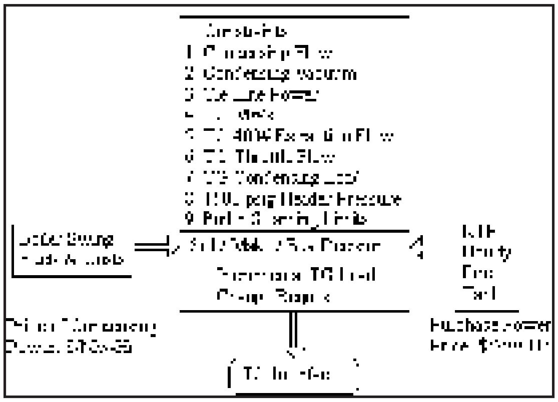
The function of the RTP control algorithm uses the mill electrical deficit to select the proper operating mode and to minimize utility cost.

RTP Control Algorithm

A schematic of the RTP tie-line control algorithm is shown in Figure 8.

The prioritized constraints are shown in the top part. They define the safe operating envelope. Using this constraint boundary, the turbine is "herded" to stay within the envelope while the tie-line control function is performed. It does not allow condensing to increase when:

Figure 8: RTP Algorithm



1. Condensing flow is high.
2. Condenser vacuum is low.
3. Purchase power is at low limit.
4. TG generated MWs is too high.
5. TG 400-psig extraction flow is too high.
6. TG condensing flow is maximized
7. TG throttle flow is high.
8. Total power boiler steam generation is very high.
9. 1,500-psig header pressure is very low.

It does not allow condensing to decrease when:

1. Condensing flow is at minimum.
2. Purchased power is at a high limit.
3. TG generated MWs is too low.
4. TG 400-psig extraction flow is too low.
5. TG condensing flow is too low.
6. TG throttle flow is too low.
7. Swing PB steam generation is very low.
8. 1,500-psig header pressure is very high.

RTP Rate Schedules

Each day the utility provides tomorrow's hourly prices by electronic mail or Internet to each RTP customer. Around 5:00 p.m. each day, tie-line control automatically downloads these prices (see Figure 9). At midnight, prices are automatically transferred to EMS for cost calculations.

The control system continuously calculates the incremental cost to generate the next megawatt hour by forced condensing. Cost is based on the incremental cost of steam generation and the quantity of steam to generate another megawatt with forced condensing. The price of condensing power is compared to the cost of purchased power. When it is less expensive to buy power, EMS decreases turbine condensing until a process constraint is encountered.

When it is less expensive to make power, EMS increases condensing until a process constraint is encountered. When the cost to buy versus generate is nearly the same, condensing is controlled to minimize consumption of fossil fuel by the power boilers. The control adjusts the turbine's load to minimize electrical costs only when all variables are within the safe operating envelope. The control sacrifices minimum cost for safe process performance.

Additional Benefits

Operations worked closely with engineering in the development of the EMS operator interfaces. Diagnostic messages are presented in plain English language. The resulting control system is very easy to understand, diagnose, tune and modify.

Figure 9: Downloaded RTP Rate Schedules

Wed, Dec 3 1997

Hour	Cents/KwHr
00:00 to 01:00	2.120
01:00 to 02:00	2.230
02:00 to 03:00	2.450
03:00 to 04:00	2.000
04:00 to 05:00	1.880
05:00 to 06:00	1.980
06:00 to 07:00	2.240
07:00 to 08:00	3.550
08:00 to 09:00	4.320
09:00 to 10:00	4.320
10:00 to 11:00	4.320
11:00 to 12:00	4.440
12:00 to 13:00	5.430
13:00 to 14:00	5.410
14:00 to 15:00	4.890
15:00 to 16:00	4.500
16:00 to 17:00	4.340
17:00 to 18:00	4.350
18:00 to 19:00	3.670
19:00 to 20:00	2.880
20:00 to 21:00	1.890
21:00 to 22:00	2.000
22:00 to 23:00	2.000
23:00 to 24:00	2.000

Tomorrow's Prices
Cents / KwHr

Transfer
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Tue, Dec 2 1997

Hour	Cents/KwHr
00:00 to 01:00	2.340
01:00 to 02:00	2.350
02:00 to 03:00	3.360
03:00 to 04:00	2.550
04:00 to 05:00	2.440
05:00 to 06:00	2.880
06:00 to 07:00	2.950
07:00 to 08:00	4.450
08:00 to 09:00	4.450
09:00 to 10:00	5.550
10:00 to 11:00	5.340
11:00 to 12:00	5.360
12:00 to 13:00	6.990
13:00 to 14:00	5.450
14:00 to 15:00	15.340
15:00 to 16:00	4.780
16:00 to 17:00	4.500
17:00 to 18:00	4.500
18:00 to 19:00	3.220
19:00 to 20:00	3.150
20:00 to 21:00	2.880
21:00 to 22:00	2.120
22:00 to 23:00	2.120
23:00 to 24:00	2.120

Today's RTP Prices
Cents / KwHr

Cents
KwHr
5.45

A reporting feature identifies process bottlenecks based on frequency distribution of encountered constraints. Two characteristics of the EMS provide this ability:

1. The process units are always operating on the edge of the optimizing envelope.
2. Encountered process constraints are highlighted on the operating displays as the process moves between optimal operating points.

Operations can identify both magnitude and frequency of operating constraints and production bottlenecks.

CONCLUSIONS

The rule-based EMS described in this paper has been customized and implemented in several powerhouses. All projects have demonstrated substantial savings. The savings attributed to this powerhouse was a minimum reduction in gas purchase of 14 percent and a total reduction in purchased energy of 13 percent while improving steam and electric generation quality and reliability.

The design is based on fuzzy logic controls. A new inference engine and defuzzification method is employed. It is the heart of this new supervisory software package. This methodology integrates online optimization and a set of prioritized constraints. A list of process, equipment and environmental constraints is converted to a set of linguistic variables (fuzzy variables), which are used to define a safe operating envelope. When the process is operating inside the envelope, the EMS optimizes the powerhouse to provide process steam and electrical power at the lowest cost possible. The EMS usually operates the process on the boundary of multiple constraints.

This new control technology is applicable for many other online process optimizations in pulp and paper mills and other industrial facilities. Many proven applications include lime kiln optimization, CO and waste gas management in petrochemical complexes, multiple gas turbines, steam generation dispatch in large utilities and mining operations.

ACKNOWLEDGEMENT

The insights and efforts of Dr. Frederick Thomasson are greatly appreciated in development of the original “Rule-Based Energy Management System.”

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